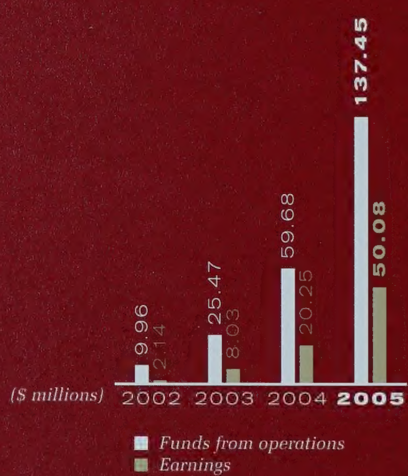
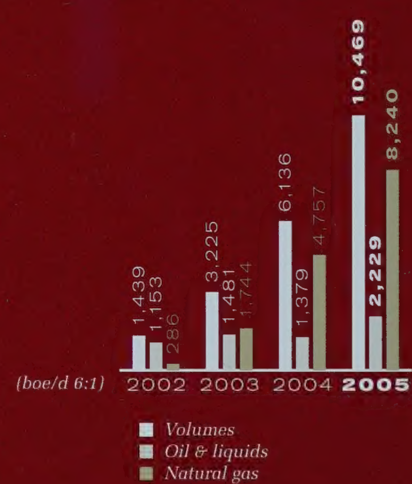
2005 ANNUAL REPORT

DUVERNAY OIL CORP.

DUVERNAY OIL CORP. IS AN ALBERTA-BASED OIL AND GAS COMPANY WITH AN AGGRESSIVE ACTIVITY PLAN FOR FUTURE GROWTH. THE COMPANY IS ENGAGED IN THE EXPLORATION AND DEVELOPMENT OF NATURAL GAS AND CRUDE OIL WITH EMPHASIS ON THE DEEPER, WESTERN PORTION OF THE WESTERN CANADIAN SEDIMENTARY BASIN IN ALBERTA AND NORTHEASTERN BRITISH COLUMBIA. DUVERNAY TRADES ON THE TORONTO STOCK EXCHANGE UNDER THE SYMBOL **DDV**.



FINANCIAL SUMMARY



PRODUCTION VOLUMES

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COVER PHOTO: *Triple Drilling Rig used in Alberta Deep Basin*

2005 HIGHLIGHTS

		2005	2004
FINANCIAL			
Oil and gas sales		**$ 208,638**	$ 94,976
Net earnings per share	*basic*	**$ 1.07**	$ 0.50
	diluted	**$ 1.02**	$ 0.48
Funds from operations per share	*basic*	**$ 2.94**	$ 1.47
	diluted	**$ 2.81**	$ 1.41
Capital expenditures		**$ 463,252**	$ 179,692
PRODUCTION			
Natural gas	*mcf*	**18,046,197**	10,446,068
Crude oil and liquids	*bbls*	**813,502**	504,860
Total crude oil, gas and liquids	*boe 6:1*	**3,821,202**	2,245,871
Crude oil, gas and liquids	*boe/d*	**10,469**	6,136
Production costs	*$/boe*	**$ 5.60**	$ 5.37
RESERVES			
Natural gas	*mmcf*		
Proved		**208,496**	125,960
Probable		**142,677**	61,216
		351,173	187,176
Oil and liquids	*mbbls*		
Proved		**5,263**	3,343
Probable		**3,018**	1,310
		8,281	4,653
Crude oil, gas, and liquids	*mboe 6:1*		
Proved		**40,012**	24,337
Probable		**26,798**	11,512
		66,810	35,849

PRESIDENT'S ADDRESS

THE ENGINE FOR LONGER TERM GROWTH REMAINS THE EXPLORATION NEW POOL WILDCAT PROGRAM AND IS THE THIRD MAIN GROWTH PLATFORM IN THE BUSINESS PLAN. DUVERNAY HAD VERY STRONG EXPLORATION PERFORMANCE IN 2005 WITH SEVERAL NEW POOL DISCOVERIES THROUGHOUT THE YEAR.

2005 was once again an excellent year for Duvernay and its shareholders. The Corporation achieved very strong financial performance and reached both the 10,000 and 15,000 boe/d production milestones. Duvernay has now grown to be a highly profitable, intermediate sized EP company in the span of just four years.

Duvernay continues to execute the original, drill bit based, EP growth plan conceived in 2001, with spectacular results. The Sunset-Groundbirch and Alberta Deep Basin operated areas are major, Basin-class gas development projects that provide the principal strong growth platforms for several years. The expanding exploration new pool wildcat program, the third major growth platform, yielded several new discoveries in 2005, at least two of which could evolve into large new pools with 2006 delineation drilling.

The groundwork has been laid for strong, predictable production and reserve growth for several years to come.

2005 PERFORMANCE REVIEW

Duvernay continued its record growth in production, cash flow, earnings and reserves during 2005.

Production averaged 10,469 boe/d in 2005, a 71% increase over 2004 levels. Natural gas production in the fourth quarter was 64,471 mcf/d compared to 35,803 mcf/d in the fourth quarter of 2004. Duvernay's production consists of light oil, condensate, natural gas liquids, and natural gas, the premium commodities in the Basin.

Funds from operations for 2005 reached $137.5 million ($2.81/share), a 99% per share increase over 2004 of $59.7 million ($1.41/share). Earnings in 2005 were $50.1million ($1.02/share) compared to $20.3 million ($0.48/share) in 2004. The strong earnings reflect the profitability of the overall business plan and the viability of the suite of subsurface targets and areas that management has selected. Cost management and reduction efforts are also reflected in these strong earnings.

The reserve base of the Corporation was grown substantially again in 2005, all the result of the conventional EP program. Duvernay made no significant acquisitions in 2005. Proved producing reserves were increased by 58% in 2005, total proved reserves grew by 64% in 2005, and proved plus probable reserves increased by 86% during the course of the year. Duvernay has an enormous inventory of gas development locations that will continue to yield very strong reserve growth for several years. The fact that many of the existing company interest wells, particularly in the Deep Basin, are early in producing life bodes well for further internal reserve increases as the full reserves from these well-bores are recognized over time. The current overall reserve life index exceeds 17.5 years.

Duvernay is pleased with the significant operating expense reductions realized during 2005. Operating costs in 2005 of $5.60/boe were top decile, and achieved in an environment of significant upwards cost pressures. The cost reductions and containment were achieved as Duvernay builds and gains control over its gas infrastructure in the two large gas project development areas. Further reductions should be achieved in 2006 with the planned start-up of the Deep Basin Cecilia gas plant expansion in the second quarter. These cost reductions are also the result of the continuing efforts of our engineering and operations staff in the office and the field.

PROVED PRODUCING RESERVES WERE INCREASED BY 58% IN 2005, TOTAL PROVED RESERVES GREW BY 64% IN 2005, AND PROVED PLUS PROBABLE RESERVES INCREASED BY 86% DURING THE COURSE OF THE YEAR.

UNIT OPERATING NETBACKS

PRODUCTION AVERAGED 10,469 BOE/D IN 2005, A 71% INCREASE OVER 2004 LEVELS. NATURAL GAS PRODUCTION IN THE FOURTH QUARTER WAS 64,471 MCF/D COMPARED TO 35,803 MCF/D IN THE FOURTH QUARTER OF 2004.

Duvernay operated 99 wells in 2005, a record, and participated in an additional 27 outside operated wells. The overall success rate was 97%. The Corporation has demonstrated the ability to operate and execute large drilling and facility projects and has all the staff in place in the critical disciplines to expand these extensive, multi-year EP projects. It is the continued outstanding performance by these staff members, both in the office and the field that has once again generated Duvernay's very strong annual performance.

INDUSTRY OVERVIEW

Oil and natural gas prices were on an unprecedented upswing throughout 2005, reaching record levels during the fourth quarter. At the time of writing in March 2006, oil prices had moderated and natural gas prices had retreated by over 50% from peak levels. Such price volatility underscores the importance of Duvernay's plans to maintain a very conservative approach to debt (maintain a debt to trailing cash flow ratio of approximately 1.0 times or less) and to continue to manage costs (reduce operating costs in 2006 to less than $5.00/boe, continue to reduce G&A/boe costs in 2006), creating some of the strongest unit netbacks in the industry.

Duvernay has selected an EP focus area in the Western Canadian Sedimentary Basin that offers liquid rich, long-life gas reserves, an area in which the company has had considerable past and current success. It is also an area that attracts the large Canadian and U.S. independents as the full cycle economic return is amongst the best in the Basin. Competition for new lands and services was even more intense in 2005 as these large companies

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PHOTOS
*1 Wild River drilling location, Alberta. 2 Sundown, British Columbia, well completion fall 2005. 3 Cecilia Gas Plant, expansion to 100 mmcf/d in Q2 2006. **ABOVE** Wild River well sign post. Fall 2005.*

PHOTOS

1 Cecilia Plant, commissioned April 2005 at 25 mmcf/d. 2 Phase II construction at Cecilia to bring capacity to 50 mmcf/d. Fall 2005. 3 Puskwa oil well flow test Q2 2005.

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expanded their programs in these areas. Despite the commodity price moderation in early 2006, there are no signs yet of reducing land sale prices or service costs.

Duvernay has utilized the year-round nature of most of its assets and operating areas to secure drilling and completion services on a continuous, long-term basis. This ensures continued access to services required to execute the EP programs and improve operating efficiency. Duvernay has built, and now controls the facilities required for current and future production volumes in its two large gas development project areas.

LONGER TERM GROWTH STRATEGIES

From inception, the Management of Duvernay has adopted a conventional, drilling based EP growth plan to build the Corporation and add value for our shareholders. We continued to execute this simple business plan in 2005, with all the growth achieved via the drill bit. This style of growth plan most effectively utilizes the skill sets and strengths of Duvernay's outstanding technical staff.

Duvernay has selected geographically contiguous operating areas located in Northwest Alberta and Northeast British Columbia. These areas have existing production, new pool discoveries, development projects, new Duvernay facilities, and rich EP project and prospect inventories. The year-round access nature of the property inventory allows for an effective methodical approach to the EP programs and the capital spending profile. The cost reductions realized in 2005 are due in part to this disciplined adherence to the geographic focus area.

WITH THE GROWTH PLAN BEING METHODICALLY EXECUTED AND THE CORPORATION DELIVERING OUTSTANDING OPERATING AND FINANCIAL RESULTS, DUVERNAY AND ITS SHAREHOLDERS LOOK FORWARD TO A SUCCESSFUL AND PROFITABLE 2006.

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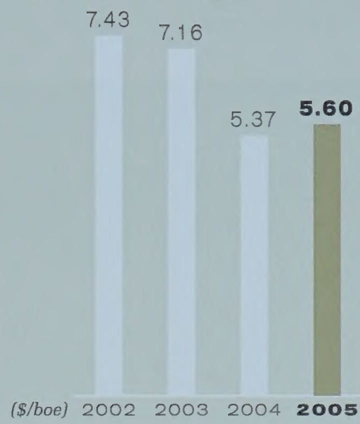


OPERATING COST PERFORMANCE

Two of the operating areas, Sunset-Groundbirch in NEBC and Wild River-Fir in the Alberta Deep Basin have grown into very large, multi-year gas development projects and essentially characterize Duvernay. Both areas have production potential in excess of 100 mmcf/d and potential reserves in excess of 500 bcf. More importantly, each of the areas have development well inventories far in excess of 400 locations, providing several years of strong, predictable production and reserve growth for Duvernay. Many of these locations are low-risk downspacing or infill locations, characteristic of expansive regional tighter gas sand plays. Both areas have demonstrated commercial uphole objectives above the principal gas pool and both have attractive deeper exploration targets, many of which are already in inventory.

Application of steadily advancing technology and operational experience has yielded steadily improving well and production results as the overall project development continues. Application of new geophysical imaging technology in Sunset-Groundbirch to optimally position development wells, has led to significantly higher initial well deliverabilities in 2005. Application of new multi-zone completion technology in conjunction with approved production comingling in the Alberta Deep Basin has also led to much higher well deliverabilities in 2005. These two expansive projects lie within Duvernay's original Basin focus area requiring only modest staff additions to accompany the large future growth profile, improving unit economics even further.

The engine for longer term growth remains the exploration new pool wildcat program and is the third main growth platform in the business plan. Duvernay had very strong exploration performance in 2005 with several new pool discoveries throughout the year. Although early in EP life, the new pools at Brassey and Fir appear particularly encouraging. The majority of the exploration program is adjacent to or underneath the two large operated complexes at Sunset-Groundbirch and in the Alberta Deep Basin. The annual exploration program has been steadily increased as annual corporate cash flow increases have been driven by the two large gas development projects. Duvernay drilled 15 new pool wildcats in 2005 and is planning a 20 to 25 wildcat program in 2006. The exploration staff has an enviable track record of delivering significant new pool discoveries every year for well over a decade. It is these exploration successes that provide the basic feedstock for future large development projects and production growth. The exploration prospect inventory has been built steadily since Duvernay's inception in 2001.

With the growth plan being methodically executed and the Corporation delivering outstanding operating and financial results, Duvernay and its shareholders look forward to a successful and profitable 2006.

Michael L. Rose

President and Chief Executive Officer
March 22, 2006

SUNSET-GROUNDBIRCH

The Sunset-Groundbirch area in British Columbia, located approximately 30 kilometers south of Fort St. John, is Duvernay's original core exploration and production area. Duvernay has interests in approximately 208,000 gross acres (140,000 net) in the Sunset-Groundbirch complex. Duvernay owns and operates two sour gas plants and three oil batteries within the complex, and will start up two additional gas plants in the first half of 2006. Production is obtained from a series of reservoirs of Triassic and Cretaceous age. The area is year-round access allowing Duvernay to drill, explore and develop on an almost continuous basis. Overall working interest production from the area increased to approximately 4,500 boe/d by the third quarter of 2005 and is expected to reach 7,000 boe/d during the second quarter of 2006.

The majority of the production in the complex is obtained from the Triassic Doig formation. This Doig discovery, made by Duvernay in late 2002, is one of the largest new gas pool discoveries in the Basin during the past three years. Duvernay now has over 50 gas wells in the pool and over 1,650 kilometres of 2D seismic data further defining the accumulation. The field is now over 50 miles long and two miles wide. Duvernay has developed a geophysical mapping method to delineate the porous Triassic Doig sandstone reservoir trend, and thus far has had a 100% drilling success rate utilizing this method. This geophysical mapping method was further refined and extended to 3D seismic data, yielding wells with much higher initial deliverabilities than the historical average. Duvernay is following up the successful 2005 3D seismic survey with a second large 3D in the Brassey-South Groundbirch area early in 2006.

The 2005 year-end GLJ Petroleum Consultants Ltd. Report recognized an average of 1.5-2.0 bcf proved plus probable reserves per well-bore in the Groundbirch pool. With ultimate development spacing of four wells per section, reserves per section of 6.0-8.0 bcf are possible. Duvernay controls 75 sections of land along the mapped trend, representing 150 locations at two gas wells per section and 300 potential drilling locations at four wells per section (including the 52 wells drilled). Using average proved plus probable reserves of 1.5-2.0 bcf per location, Duvernay's net potential reserves from just two gas wells per section range from 225-300 bcf.

Gas production from the Groundbirch discovery is processed at two sour gas treating facilities, constructed by Duvernay. These plants utilize an amine system to sweeten the 0.3 to 0.5% H_2S gas to pipeline sales quality. The Duvernay gas plants are tied directly into the Duke sales system, south of the McMahon plant. The capacity of the plants is approximately 12.5-15.0 mmcf/d of sales gas allowing the plant to remain within existing emission guidelines for new gas plants in British Columbia. Two additional Duvernay owned and operated plants are being built in the first half of 2006, at Brassey and Sundown. The start-up of these plants will take total production from the complex to 50 mmcf/d. Controlling the gas infrastructure in this rapidly developing EP area provides Duvernay with a significant competitive advantage.

As is often the case when a large development drilling program is embarked upon, numerous discoveries in uphole horizons occur. This has been the case at Sunset-Groundbirch in 2004-2005 with several new pools encountered. The largest of these to date is the discovery of Cretaceous Cadomin gas at Brassey in spring 2005. Duvernay now has 10 successful wells into this reservoir, an areally expansive tight gas resource play. Duvernay's land base for this new Cadomin pool could ultimately equate to over 100 drilling locations at just two wells per section.

Exploration for additional new Doig pools and deep Triassic Montney gas pools was initiated in the second half of 2005; this effort will be expanded in 2006.

Duvernay has also been successful in discovering oil and gas in other objectives along the Triassic Doig exploration trend. Of the 52 exploration and development wells drilled into the Doig play, 30 have found hydrocarbons in other horizons. These include the Triassic Montney, Halfway, Cecil, Artex and North Pine formations, as well as the Cretaceous Paddy, Gething and Bluesky formations. These pools will be evaluated by further drilling and, if justified, will be brought on-stream as well.

The Triassic Doig gas wells qualify for numerous facets of the unconventional gas royalty reduction program announced by the British Columbia government in May of 2003.

BC
AB
Duvernay Land
Gas Wells
Plant
Twin Duke Sales Gas Line
Duvernay Pipelines
R19
R18
R17
R16W6
T81
T80
T79
T78
T77
Sunset
Saturn
Twin Duke Sales
Gas Lines
Groundbirch
Brassey
Sundown

ALBERTA DEEP BASIN

Duvernay's Alberta Deep Basin complex, located approximately 250 kilometers west of Edmonton, Alberta, is a broad, multi-objective natural gas charged play area. It is currently one of the most active gas exploration and production areas in the entire Western Canada Sedimentary Basin. The area has evolved into Duvernay's largest producing area with production of 9,000 boe/d by year-end 2005.

The entire Cretaceous stratigraphic section, between the Cardium and the Cadomin, is gas saturated, one of the principal characteristics of the Alberta Deep Basin. Duvernay views the area as principally highlighted by an areally pervasive gas field in the Cretaceous Cadomin formation, the sandstone and conglomerate unit at the base of the Cretaceous. This Cadomin gas field extends over 30 townships and is composed of several gas pools. There are more highly permeable/higher gas well deliverability areas and tighter regions within the field. The Cadomin is amenable to gas downspacing at up to four wells per section. Typical Deep Basin wells have initial deliverability of 1.5 mmcf/d and recover 1.5 to 3.0 bcf of reserves over productive life. Duvernay did not discover this regional field, but has captured a significant portion of the opportunity. The field is being simultaneously developed by several operators, generally the large Canadian and U.S. independents. Duvernay had drilled over 100 Cadomin gas wells by the end of 2005 into this gas field, achieving above average Cadomin production and drilling results for the area, which bodes well for long-term per well reserve recovery. Including downspacing, Duvernay has over 450 Cadomin development locations remaining at year-end.

Over 90% of Duvernay's Cadomin gas wells at Wild River-Fir also contain at least two additional commercial uphole Cretaceous gas horizons. These additional zones significantly increase per well-bore reserves and productive capability. Commercial uphole Cretaceous targets include the Gething, Bluesky, Notikewan, Falher, Dunvegan, Viking and Cardium horizons and Duvernay has successful completions in all of these zones. Application of new multi-zone completion technology coupled with comingling approval has allowed for completion of multiple horizons and subsequent flow up one tubing string. Duvernay conducted several completions of this style in the second half of 2005 yielding wells with higher initial production rates and gentler initial production declines. As comingling approvals are granted by the Alberta government, the company intends to migrate towards this completion technique for all Deep Basin wells. This new completion technology offers the opportunity for significant production volume upside from the Deep Basin in the 2006-2008 time frame.

Duvernay drilled 70 successful wells in the Deep Basin area in 2005, with a 100% success rate. During the second half of 2005 Duvernay operated seven drilling rigs in the complex and that pace of activity has continued in 2006. 2005 Deep Basin drilling highlights included continued delineation drilling success in the Wroe Creek area, high gas rate comingled wells at Cecilia, successful completion of previously untested gas zones (Falher, Dunvegan, Belly River) and very high rate wells at South Fir-Oldman. The company plans 90 wells in 2006, including some initial downspacing locations at two wells per section.

The major 2005 highlight for Duvernay in the Deep Basin was construction and start-up of the 100% Duvernay owned and operated Cecilia 15-4 gas plant. The plant was constructed in March and commenced production in April of 2005. The initial capacity of 25 mmcf/d was expanded in the fall to 50 mmcf/d to accommodate the successful, ongoing development drilling program. A second expansion, to a full 100 mmcf/d capacity, is underway with completion and start-up expected in the second quarter of 2006. The required field gathering and compression systems have also been constructed and are being modified, as required, to meet increasing gas volumes. The Cecilia plant, located adjacent to the main sales gas pipeline system in the area, is now the central facility hub to Duvernay's Deep Basin operations. Routing the majority of Duvernay's gas volumes to this plant will allow for continued operating cost reductions in 2006.

Duvernay also has a deep exploration program targeting deeper Devonian and other objectives beneath the ongoing Cretaceous gas development area. An aggressive new pool wildcat drilling program was undertaken in 2005 and resulted in new pool discoveries at Fir and Pine. These new pools will be further delineated in 2006.

The 2006 new pool wildcat program will be expanded and includes multiple large reserve potential Devonian targets.


BC
AB
Duvernay Land
2004/2005 Gas Wells
Plant
Duvernay Pipelines
Pipelines
R26
R25
R24
R23
R22
R21
R20
R19
R18
R17W5
T61
T60
T59
T58
T57
T56
T55
T54
T53
T52
Bigstone
Nova Line
Fir
Borland
15-4 Duvernay Plant
Wroe Creek
Oldman
Wild River
Wild River Plant
Wild Hay
11-22 Central Facility
Obed
Pine
Marsh
Pedley
Sundance
Edson

EXPLORATION PROGRAM

Duvernay's long-term growth and future development projects will be generated by its exploration program. Duvernay has always conducted a relatively large annual new pool wildcat program compared to both similar and larger size industry peers. Duvernay has been methodically assembling its exploration prospect inventory since 2001, and now has over 75 new pool locations/ prospects in inventory, as well as several new, large scope plays. Some of these prospects, if successful, could lead to significant development projects with inherent large reserve and production potential. Duvernay has a very strong exploration staff with a long history of successful new pool exploration. During the past decade, members of Duvernay's exploration staff have collectively made a series of new pool discoveries every year. Typically, one or two of these are larger pool discoveries that often initiated a broad new exploration play. Duvernay's exploration team is intimately familiar with exploration plays at all levels in the stratigraphic column and have made discoveries at all levels in the column.

2005 was once again a year characterized by very strong exploration performance for Duvernay. After lengthy surface and well licensing issues, Duvernay drilled its first well in the Pembina-Brazeau Nisku oil play. The 6-11 well discovered a new oil pool and has produced at rates as high as 1,200 boe/d. An additional new pool wildcat is planned in 2006 at Pembina.

Duvernay delineated a major northwards extension of the originally defined Cretaceous Deep Basin at Brassey, B.C., discovering a new gas pool in the Cretaceous Cadomin formation in May 2005. By March 1, 2006, Duvernay had 10 delineation wells drilled into this potentially large gas pool. Initial indications suggest that this discovery could evolve into an additional large gas resource play to complement the Triassic Doig EP effort.

Duvernay is attempting to find additional new pools in the Triassic Doig section, analogous to the company's original Doig discovery. Two new pool wildcats were cased and successfully tested in 2005. This new pool program will be accelerated in 2006.

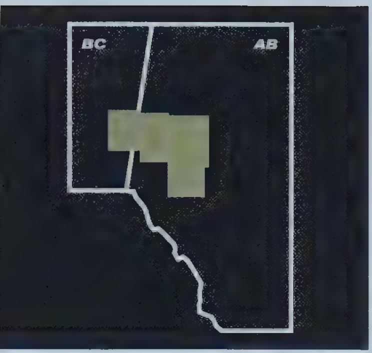
At Puskwa, Alberta, the company cased an exciting new pool wildcat Devonian basal sand oil well in the fourth quarter of 2005. High oil rate competitor wells have been drilled in the immediate area, a play area that the Duvernay exploration staff has been involved in for over 10 years. Duvernay plans considerable additional seismic and drilling on its significant area land position.

In the Alberta Deep Basin, the company cased two deep exploration wells, which are currently being tested and evaluated.

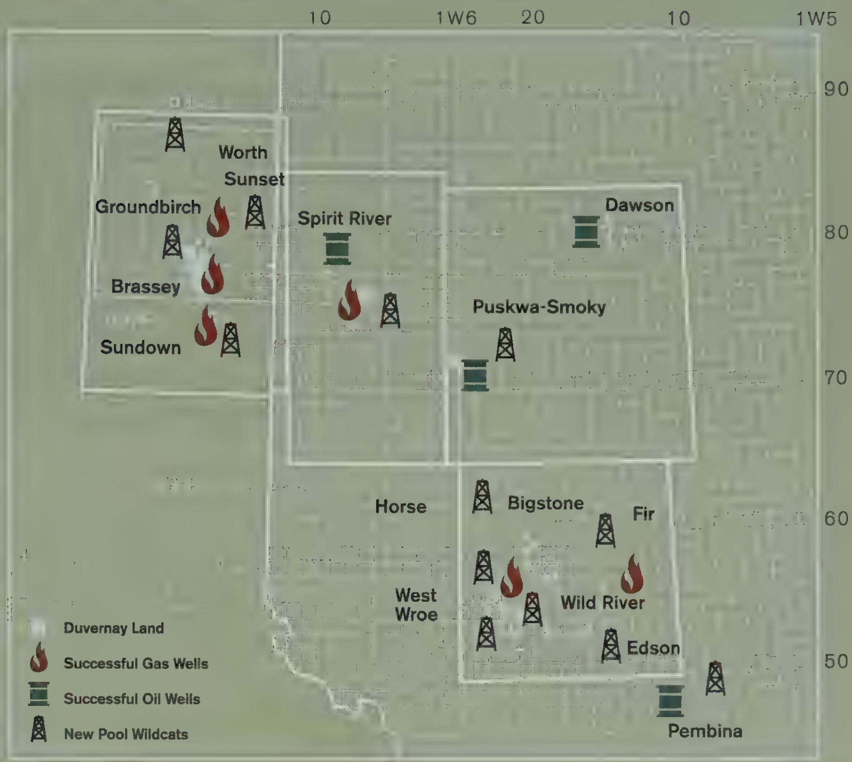
The majority of the exploration prospect inventory thus far is within the four defined operating complexes, as the Corporation is continuing to maintain its geographic focus. Many of the exploration targets lie below the existing large ongoing gas development projects where the gas infrastructure is currently being constructed. The 2006 new pool wildcat program will be the largest in the history of Duvernay. Targets and prospects being pursued include:

- Multiple new pool Triassic Doig and Montney targets in northeast B.C.
- Devonian gas targets in four different formations beneath the Wild River-Fir-Alberta Deep Basin operating area.
- Paleozoic gas targets beneath the Sunset-Groundbirch Triassic operating complex.
- Oil charged Devonian Nisku stratigraphic traps in the greater Pembina area.
- New pool Jurassic Rock Creek targets in the Wild River-Fir complex.
- Devonian objectives in the greater Spirit River area of Alberta.
- Devonian oil targets in the greater Puskwa-Smoky area of Alberta.

A total of approximately 20 to 25 new pool wildcats are planned in 2006. Duvernay's exploration staff will also continue to expand the prospect inventory in 2006, providing a healthy feedstock for exploration drilling in 2007 and 2008. Duvernay continues to pursue select exploration opportunities outside the main EP focus areas.



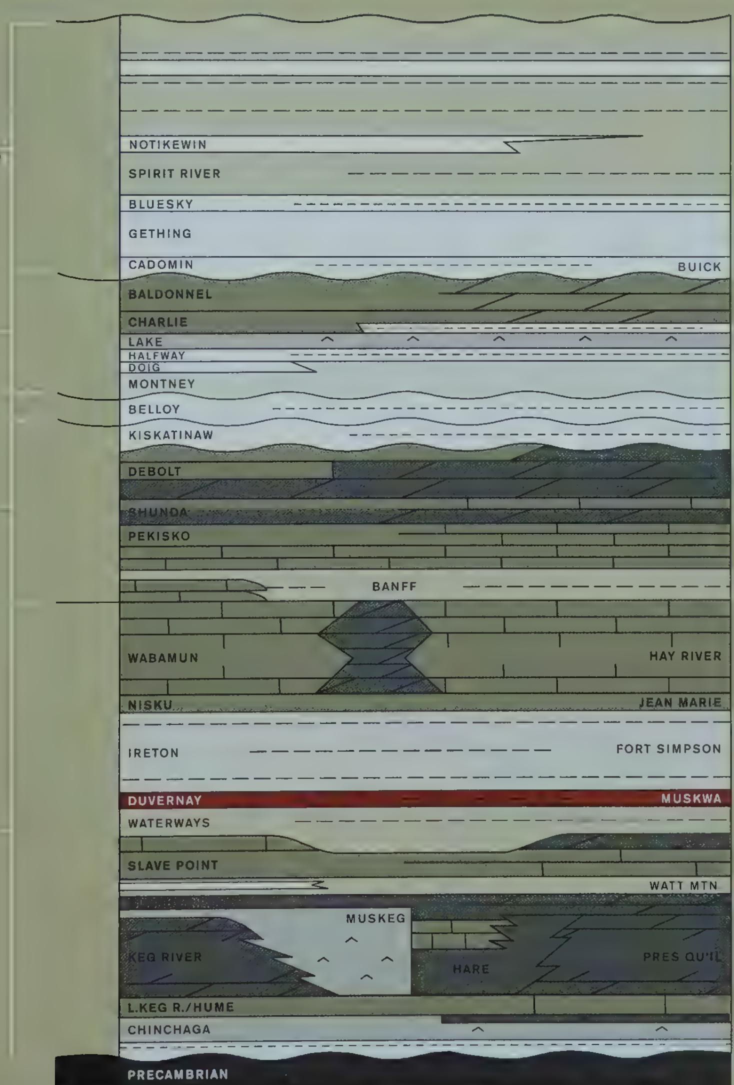
EXPLORATION 2005-2006 NEW POOL WILDCATS



2005-Q1/06 SUCCESSES

- Pembina Nisku
- Dawson Bluesky
- Brassey Cadomin
- Puskwa Devonian
- Fir Nordegg
- Sunset Doig
- Sundown Doig
- Spirit River Oil

STRATIGRAPHIC COLUMN



ENVISAGED PLAYS

LARGE STRATIGRAPHIC TRAPS IN DELTAIC SANDS

STRATIGRAPHIC TRAPS IN GAS SATURATED SANDS

STRATIGRAPHIC TRAPS AT SUBCROP, LOCAL POROUS LENSES

LOCAL POROUS SAND LENSES STRATIGRAPHIC AND STRUCTURAL TRAPS

LARGE SAND PINCH-OUTS LOCAL STRUCTURAL CLOSURES

STRUCTURAL CLOSURES

STRATIGRAPHIC TRAPS AT SUBCROP AND IN LOCAL POROUS SHOALS

POTENTIAL LARGE CARBONATE ISLANDS AND PLATFORMS

DOLOMITIZATION ADJACENT TO LARGE NORMAL FAULT ZONES

LOCAL STRUCTURAL CLOSURES

SLAVE POINT BANKS AND ISLANDS
UPPER Ds ISLANDS
SLAVE POINT DOLOMITE AT Dpq MARGINS
MID-Ds DOLOMITE IN STRUCTURAL CLOSURES

PINNACLE REEFS ENCASED IN ANHYDRITE OR SHALE LOWER Dpq SHOALS

CAMBRIAN GAS PLAYS

MANAGEMENT'S DISCUSSION AND ANALYSIS

YEAR ENDING DECEMBER 31, 2005 COMPARED TO THE YEAR ENDING DECEMBER 31, 2004

This management's discussion and analysis should be read in conjunction with Duvernay's comparative audited annual financial statements for the year ended December 31, 2005 and comparative information included therein. This management's discussion and analysis is dated March 22, 2006.

Certain information set forth in this management's discussion and analysis contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, many of which are beyond Duvernay's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the competition for qualified personnel and management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be incorrect and, as such, undue reliance should not be placed on forward-looking statements. Duvernay's actual results, performance or achievement could differ materially from those expressed in or implied by these forward-looking statements, and accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Duvernay will derive therefrom. Duvernay disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as expressly required by applicable securities laws.

Funds from operations and operating netback are not recognized measures under GAAP. Management believes that in addition to net income, funds from operations and operating netback are useful supplemental measures as they demonstrate Duvernay's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Investors are cautioned, however, that these measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of Duvernay's performance. Duvernay's method of calculating these measures may differ from other companies and accordingly, they may not be comparable to measures used by other companies. For these purposes, Duvernay defines funds from operations as cash provided by operations before changes in non-cash operating working capital and abandonment costs incurred. Operating netback is defined as revenue less royalties and operating expenses.

Per barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6:1). (Barrel of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6mcf:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.)

THIS MANAGEMENT'S DISCUSSION AND ANALYSIS SHOULD BE READ IN CONJUNCTION WITH DUVERNAY'S COMPARATIVE AUDITED ANNUAL FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2005 AND COMPARATIVE INFORMATION INCLUDED THEREIN.

PRODUCTION

Production volumes for the year ended December 31, 2005 averaged 10,469 boe/d compared to 6,136 boe/d for the same period in 2004. Fourth quarter 2005 production volumes averaged 13,601 boe/d, an increase of 87% over the 7,275 boe/d reported for the same quarter in 2004. On a year over year basis, 2005 production increased by 71% over 2004. The following table summarizes production volumes by product:

	Three Months Ended Dec. 31			Year Ended Dec. 31		
	2005	2004	% change	**2005**	2004	change
Crude oil and liquids (bbl/d)	**2,856**	1,307	119%	**2,229**	1,379	62%
Natural gas (mcf/d)	**64,471**	35,803	80%	**49,442**	28,541	73%
Oil equivalent – boe's	**1,251,314**	669,265	87%	**3,821,202**	2,245,871	71%
Oil equivalent – boe/d	**13,601**	7,275	87%	**10,469**	6,136	71%

Duvernay's production profile continued to be natural gas weighted during 2005 with 79% natural gas and 21% oil and liquids, consistent with full year 2004 with 78% natural gas and 22% oil and natural gas liquids. Production by property in Q4 2005 compared to Q4 2004 is as follows:

	Three Months ending Dec. 31		
Average boe/d	**2005**	2004	change
Northeast B.C.	**4,052**	3,421	18%
Deep Basin	**6,845**	3,057	124%
Peace River/Pembina/Other	**2,704**	797	239%
Total	**13,601**	7,275	87%

REVENUE & ROYALTIES

Revenue from petroleum and natural gas sales for the year ended December 31, 2005 was $213.0 million representing a 120% increase over revenue of $96.7 million for the same period in 2004. The revenue increase attributed to volume growth was $65.6 million while the revenue increase attributed to product price improvement was $50.7 million. Revenue includes all petroleum and natural gas sales and income from third party natural gas processing, and includes the realized portion of commodity hedging activities. The Corporation has reported transportation cost separately in the statement of earnings and retained earnings as a deduction from gross revenue. Realized oil and liquids prices for 2005 averaged $55.73 per barrel (including realized hedging losses of $3.11 per barrel) compared to $43.59 per barrel in 2004 (including realized hedging losses of $4.75 per barrel). Natural gas prices also improved on a year over year basis averaging $8.93/mcf for 2005 compared to $6.86 for 2004. During 2005, Duvernay estimates that natural gas marketing operational performance combined with natural gas hedges have yielded the company $2.2 million ($0.12/mcf) in additional gross revenue over the comparable monthly indices. Prices are summarized as follows:

DUVERNAY REALIZED PRICES

	Three Months Ended Dec. 31			Year Ended Dec. 31		
	2005	2004	change	**2005**	2004	change
Crude oil and liquids	**$ 59.86**	$ 42.81	40%	**$ 55.73**	$ 43.59	28%
Natural gas	**$ 10.72**	$ 7.12	51%	**$ 8.93**	$ 6.86	30%
Price/boe	**$ 63.40**	$ 42.74	48%	**$ 54.02**	$ 41.69	30%

BENCHMARK OIL AND GAS PRICES

	Three Months Ended Dec. 31			Year Ended Dec. 31		
	2005	2004	change	**2005**	2004	change
Oil						
NYMEX U.S.	**$ 60.05**	$ 48.27	24%	**$ 56.70**	$ 41.47	37%
Edmonton Par Cdn.	**$ 72.22**	$ 58.03	24%	**$ 69.85**	$ 53.27	31%
Natural Gas						
NYMEX U.S.	**$ 12.88**	$ 7.26	77%	**$ 9.00**	$ 6.18	46%
AECO Cdn	**$ 11.61**	$ 6.73	73%	**$ 8.81**	$ 6.59	34%
Currency	**$ .8521**	$ .8198	4%	**$ .8256**	$ .7688	7%

	Three Months Ended Dec. 31		Year Ended Dec. 31	
	2005	2004	**2005**	2004
Revenue*: *($ thousands)*				
Oil and NGL's	**$ 16,458**	$ 6,081	**$ 47,866**	$ 24,407
Hedge	**(730)**	(932)	**(2,533)**	(2,398)
	$ 15,728	$ 5,149	**$ 45,333**	$ 22,009
Natural gas	**63,609**	23,454	**161,078**	71,621
Processing & rental income	**796**	490	**2,227**	1,346
Gross revenue*	**$ 80,133**	$ 29,093	**$ 208,638**	$ 94,976
Interest income	**–**	(56)	**–**	–
Total revenue*	**$ 80,133**	$ 29,037	**$ 208,638**	$ 94,976

**Revenue is reduced by transportation costs*

Duvernay's royalties are summarized as follows:

	Three Months Ended Dec. 31		Year Ended Dec. 31	
	2005	2004	**2005**	2004
Royalties: *($ thousands)*				
Oil and liquids	**$ 4,114**	$ 1,164	**$ 10,787**	$ 4,993
Natural gas	**11,973**	2,969	**31,185**	13,517
ARTC	**(125)**	–	**(525)**	(500)
	$ 15,962	$ 4,133	**$ 41,447**	$ 18,010

For the year ended December 31, 2005 the average effective royalty rate was 20% compared to 19% for the same period in 2004. The rate has held constant as the Corporation continues to benefit from deep gas royalty holidays on new wells in Alberta and the benefits realized through the British Columbia low productivity natural gas well program. Duvernay records the benefits provided by the various provincial incentive programs only in the period in which the benefit has been approved by the provincial regulatory agency. Consequently, in the fourth quarter, the Corporation had an effective royalty rate of 20% compared to 14% for the same quarter in 2004. Duvernay has applied for royalty holidays on 26 wells which have approximately a $2 million royalty refund due to Duvernay when these applications are approved.

OPERATING EXPENSES

Operating expenses include all periodic lease and field level expenses and include no income recoveries for processing third party volumes. Duvernay's lease operating expenses on a barrel of oil equivalent basis went from $5.37/boe in 2004 to $5.60/boe in 2005. Total operating expenses for 2005 were $21.4 million compared to $12.1 million for 2004. This absolute increase is entirely attributable to increases in production volumes. For the fourth quarter of 2005, operating expenses were relatively unchanged compared to the same quarter in 2004 ($5.74/boe compared to $5.67/boe). For 2005, the Corporation managed to keep unit operating costs in check in spite of having to deal with inflationary pressures arising from competition for many field services. On a barrel of oil equivalent basis, third party processing, treating and compression costs rose to $1.55 up from $1.40 in 2004, representing 28% of total operating expenses. Early in 2006, 15 mmcf/d of gas flowing through third party facilities has been rerouted into the Duvernay owned Cecilia gas plant. This initiative, combined with new incremental volumes going into Duvernay owned and operated facilities is expected to bring unit operating expenses down in 2006.

GENERAL & ADMINISTRATIVE EXPENSES

General and Administrative Expenses are summarized on the table below as follows:

	Three Months Ended Dec. 31		Year Ended Dec. 31	
($ thousands)	**2005**	2004	**2005**	2004
General & administrative expenses	**$ 3,799**	$ 2,828	**$ 11,234**	$ 7,718
Administrative and operating recovery	**(285)**	(98)	**(1,288)**	(457)
Capital recovery	**(1,615)**	(687)	**(4,718)**	(1,962)
Capitalized G&A	**(600)**	(607)	**(1,707)**	(1,747)
Stock based compensation	**1,477**	413	**3,881**	1,165
	$ 2,776	$ 1,849	**$ 7,402**	$ 4,717
$/boe	**$ 2.22**	$ 2.76	**$ 1.94**	$ 2.10

General and administrative expenses for the twelve months ending December 31, 2005 increased to $7.4 million from $4.7 million for the same period in 2004. On a per unit of production basis, the rate decreased from $2.10/boe in 2004 to $1.94 in 2005. On a cash basis, G&A for 2005 dropped to $0.92/boe from $1.58/boe in 2004 as fixed costs are spread over a larger production volume. The percentage of head office expenses attributed to exploration activities and capitalized was 35% consistent with 2004. Fourth quarter 2005 G&A cash costs of $1.04 per boe are significantly lower than the same quarter for 2004 of $2.15 per boe. The Corporation's strong performance in the equity markets combined with the issuance of 1.3 million stock options in 2005, drove stock based compensation costs for 2005 up by 233% to $3.9 million. On a barrel of oil equivalent basis, this non-cash cost increased to $1.02/boe from $0.52/boe in 2004.

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and site restoration expense increased to $60.1 million during 2005 from $27.2 million during 2004. On a dollars per boe basis, full year unit of production DD&A increased in 2005 to $15.73 from $12.12 in 2004, an increase of 30%. The rate increase is primarily attributable to large 2005 investments in facilities (22% of total capital compared to 15% in 2004). The 2006 capital program contemplates dedicating 78% of total capital to drilling and completions. For the fourth quarter of 2005 the DD&A rate of $19.82/boe is compared to $15.47 for the fourth quarter of 2004. The increase in rate is primarily attributable to the high level of facilities spending in the fourth quarter combined with higher than anticipated future development costs associated with proved reserves.

INCOME TAXES

Duvernay did not incur any cash tax expense in 2005 other than Large Corporation Tax, which totaled $1,228,000. Other than Large Corporation Tax Duvernay does not expect to pay any cash taxes in 2006 based on existing tax pools, planned capital expenditures and the most recent forecast of 2006 taxable income. Although current tax horizons depend on product prices, production levels, and the nature, magnitude and timing of capital spending, the Corporation currently believes that no cash income tax will be payable for one to two years. Duvernay's tax pools at December 31, 2005 and December 31, 2004 are as follows:

	Maximum Deduction %	**2005** *($ millions)*	2004 *($ millions)*
COPGE	10	**$ 71**	$ 52
CDE	30	**249**	99
CEE	100	**83**	81
UCC	25	**165**	59
Other		**10**	7
		$ 578	$ 298

The future income tax provision for the fourth quarter of 2005 was 31% of pre-tax income compared to 24% for the same period in 2004. The fourth quarter 2004 effective rate was low for two reasons. The first factor is that Duvernay enjoyed a lower Crown royalty rate than originally forecast resulting in lower Crown royalty rates compared to the resource allowance. The Corporation also amended its 2003 federal income tax return giving rise to a positive adjustment to the 2003 resource allowance calculation which is incorporated in the results for the fourth quarter of 2004.

FUNDS FROM OPERATIONS AND EARNINGS

Funds From Operations increased by 130% to $137.5 million ($2.81 per diluted Equity Share) for the twelve months ending December 31, 2005 from $59.7 million ($1.41 per diluted Equity Share) for the comparable period in 2004 due to the combination of growth in production volumes and stronger operating netbacks, which improved by 33% averaging $37.57/boe compared to $28.30 for 2004. Full year funds from operations guidance announced in November of 2005 was $148 million ($2.98/diluted share) which was 7% higher than actual results, primarily due to full year production of 10,469 boe/d being slightly lower than November 2005 guidance of 10,700 boe/d. After-tax earnings improved by 147% for 2005 to $50.1 million when compared to 2004 of $20.3 million. On a per share basis, diluted earnings improved by 113% to $1.02 per share for 2005 compared to $0.48 for 2004.

	Three Months Ended Dec. 31			Year Ended Dec. 31		
	2005	2004	change	**2005**	2004	change
Funds from operations per equity share [1]	**$ 1.04**	$ 0.42	148%	**$ 2.81**	$ 1.41	99%
Earnings per equity share [1]	**$ 0.35**	$ 0.14	150%	**$ 1.02**	$ 0.48	113%
Operating netback per boe	**$ 44.90**	$ 30.89	45%	**$ 37.57**	$ 28.30	33%

note: (1) diluted

LIQUIDITY AND CAPITAL RESOURCES

Duvernay invested $463.3 million in 2005 compared to $179.7 million in 2004, as set out in the following table.

($ thousands)	Year Ended Dec. 31 **2005**	2004
Land and seismic	**$ 46,587**	$ 19,186
Drilling and completions	**289,928**	131,817
Facilities	**103,224**	26,824
Property acquisitions	**52,908**	(88)
Property dispositions	**(31,262)**	–
Other	**1,867**	1,952
Total	**$ 463,252**	$ 179,691

Duvernay participated in the following equity financings during 2005, the proceeds from which were dedicated to an expanded capital spending program:

April	flow-through-private placement	1,150,000	$35.50	$40,825,000
June	common-short term prospectus	1,800,000	$27.75	$49,950,000
October	flow-through-private placement	800,000	$52.00	$41,600,000

The Corporation estimates that it has completed its commitment to invest $40.8 million in exploration spending from the April 2005 flow-through and that $32.5 million of the October 2005 flow-through has been spent by December 31, 2005.

During the year, the Corporation also issued 710,000 common shares as consideration for the purchase of two producing properties.

At December 31, 2005, Duvernay had a working capital deficiency of $40.2 million and the bank line was drawn to $175.5 million for net debt of $215.7 million or 1.56 times annual trailing funds from operations. In January 2006, the Corporation finalized the expansion of its credit facility from $200 million to $250 million. The credit facility is an arrangement with a Canadian chartered bank bearing interest on a variable grid currently 95 basis points over the prevailing bankers' acceptance rate. Security for the facility includes a general security and a $500 million demand loan debenture secured by a first floating charge over all assets.

Duvernay also completed a short form prospectus equity financing for $55.6 million by issuing 1,250,000 common shares at $44.50 per share. This equity financing completed in January 2006 improved Duvernay's balance sheet resulting in pro forma net debt of approximately $160 million or 1.15 times trailing funds from operations.

The Corporation's average interest rate on borrowed funds increased slightly in 2005 to 4.55% from 4.34% in 2004.

During 2005, Duvernay drilled 126 gross (85.7 net) wells, with a success rate of 97% resulting in 4 oil wells, 120 gas wells, and 2 suspended or abandoned wells. In addition, a new gas plant in the Cecilia area of the Alberta Deep Basin was commissioned with capability to process 50 mmcf/d of sales natural gas, 100% owned by Duvernay. In the second quarter of 2006, Duvernay is scheduled to complete construction of a 50 mmcf/d gas plant expansion at Cecilia along with two new plants in Northeast BC to process 25 mmcf/d of Doig and Cadomin gas.

The Corporation invested $103 million in 2005 in facilities and infrastructure, $78 million of which is dedicated to the Alberta Deep Basin in order to serve the reserves assigned in this region, as well as to support future growth. Duvernay also continued to grow its undeveloped land base aggressively by spending $39.2 million at Crown land sales resulting in 67,000 gross acres (56,000 net) primarily in the Alberta Deep Basin and the Cadomin and Doig resource play of Northeast BC.

Duvernay's base capital budget for 2006 is $400 million with approximately $90 million allocated to exploration activities and approximately $310 million allocated to development drilling and facilities. The 2006 budget contemplates drilling 168 wells for $316 million, or 78% of the 2006 capital program. This is in contrast to 2005 when $290 million was invested in drilling or 63% of total capital spending. This capital program will be funded through a combination of cash flow and bank debt.

The Corporation currently forecasts 2006 Funds from Operations to be $250 – $300 million depending on product prices, with the balance being funded from bank debt.

As at December 31, 2005, the Corporation had issued and outstanding common shares of 49,345,308 and outstanding stock options of 4,653,284. As at March 22, 2006 the Corporation had issued and outstanding common shares of 51,204,808 and outstanding stock options of 4,273,784.

FINANCIAL INSTRUMENTS

The Corporation makes use of specific commodity hedging instruments that serve two primary business objectives. The first objective is to reduce the variability in cash flows from fluctuations in product prices to ensure a source of funding for the 2005 and 2006 capital program. The second objective is to fix the rate of return on capital invested in the gas prone resource projects. The Board of Directors has approved a policy permitting management to hedge up to a fixed percentage of budgeted corporate production.

Duvernay has entered into all hedging transactions with the same party that the commodity is physically sold to, avoiding the need to provide credit in the event that the hedges are at prices below prevailing prices. The most significant risk with the commodity hedges is that the prevailing product prices are higher than those committed to in the hedging contract. The Corporation partially mitigates this risk by including collars in its hedging portfolio. A less significant risk relates to the Corporation's ability to supply the production at future dates. This risk is managed by keeping the percentage of total budgeted production below 25% and by entering into the hedging contracts at multiple delivery points.

During 2005, the Corporation's Petroleum and Natural gas sales of $213.0 million included realized hedging losses of $333,000. At the end of 2005, Duvernay assessed the prevailing market value of similar contracts to those that were unsettled at year end and has estimated a net cost to settle these instruments to be approximately $1.2 million. Completing a similar assessment at February 28, 2006 results in a receipt to the Corporation of $11.7 million due to gas price erosion in the first two months of 2006.

Time Period	Type of Contract	Quantity Control	Contract Price
2006 January – June	Put (floor)	100 bbls/day	$50.00 U.S. W.T.I.
2006 January – March	Put (floor)	100 bbls/day	$50.00 U.S. W.T.I.
2006 April – June	Put (floor)	100 bbls/day	$50.00 U.S. W.T.I.
2006 July – September	Put (floor)	100 bbls/day	$50.00 U.S. W.T.I.
2006 January – March	Physical (swap)	15,000 gj's/day	$9.05 Cdn/gj average
2006 April –October	Physical (swap)	5,000 gj's/day	$9.32 Cdn/gj average
2006 January – March	Put (floor)	5,000 gj's/day	$9.00 Cdn/gj
2006 January – March	Put (floor)	2,000 gj's/day	$12.00 Cdn/gj
2006 April – October	Call (ceiling)	5,000 gj's/day	$9.65 Cdn/gj
2006 April – October	Call (ceiling)	2,000 gj's/day	$12.45 Cdn/gj
2006 April – October	Collar	2,000 gj's/day	$6.86 Cdn/gj Floor $9.66 Cdn/gj Ceiling
2006 April – October	Collar	3,000 gj's/day	$10.00 Cdn/gj Floor $11.00 Cdn/gj Ceiling

Subsequent to the end of the year, the Corporation has not entered into any other commodity hedging instruments.

DUVERNAY OIL CORP.

SELECTED QUARTERLY INFORMATION

	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
PRODUCTION								
Crude oil and liquids (bbls)	**262,755**	**197,497**	**205,527**	**147,723**	120,282	132,187	129,507	122,884
Gas (mcf)	**5,931,351**	**4,452,299**	**4,218,977**	**3,443,570**	3,293,899	2,719,770	2,589,721	1,842,678
Oil equivalent (boe)	**1,251,314**	**939,547**	**908,690**	**721,651**	669,265	585,482	561,127	429,997
Crude oil and liquids (bbls/d)	**2,856**	**2,147**	**2,259**	**1,641**	1,307	1,437	1,423	1,350
Gas (mcf/d)	**64,471**	**48,395**	**46,362**	**38,262**	35,803	29,563	28,458	20,249
Oil equivalent (boe/d)	**13,601**	**10,212**	**9,986**	**8,018**	7,275	6,364	6,166	4,725
FINANCIAL								
($ thousands, except as noted)								
Revenue, net of royalties and transportation	**64,170**	**42,898**	**33,217**	**26,906**	24,904	19,393	18,895	13,774
Funds from operations	**53,828**	**35,758**	**26,495**	**21,372**	19,064	15,570	14,951	10,091
Per share basic	**1.10**	**0.75**	**0.58**	**0.48**	0.44	0.37	0.37	0.26
Net earnings	**18,287**	**15,532**	**8,537**	**7,719**	6,213	5,881	4,962	3,198
Per share basic	**0.37**	**0.32**	**0.19**	**0.17**	0.14	0.14	0.12	0.08
Per share diluted	**0.35**	**0.31**	**0.18**	**0.16**	0.14	0.13	0.11	0.08
Total assets	**827,263**	**672,868**	**548,268**	**474,245**	393,440	327,031	287,471	266,207
Bank debt	**175,481**	**141,792**	**79,190**	**68,859**	40,724	27,597	23,678	17,728
Cash and working capital (deficiency)	**(40,180)**	**(28,005)**	**(8,602)**	**(52,366)**	(13,439)	(18,184)	443	(15,678)
Basic outstanding shares	**49,345**	**47,856**	**45,844**	**44,436**	42,857	41,671	39,992	38,096
PER UNIT								
Gas, net of transportation ($/mcf)	**10.72**	**8.84**	**7.58**	**7.59**	7.12	6.65	7.11	6.32
Crude oil and liquids, net of transportation ($/bbl)	**59.86**	**59.85**	**51.48**	**48.76**	42.81	47.95	43.71	39.55
Revenue, net of transportation ($/boe)	**63.40**	**54.47**	**47.16**	**46.22**	42.74	41.74	42.92	38.38
Operating netback ($/boe)	**44.90**	**39.24**	**31.19**	**31.02**	30.89	27.55	28.62	24.86

Duvernay's quarterly and annual growth in production volumes, gross revenue, per share funds from operations and per share earnings is primarily attributed to an active exploration and development drilling program.

DUVERNAY OIL CORP.

SELECTED ANNUAL INFORMATION

	2005	2004	2003
			(restated)
PRODUCTION			
Crude oil and liquids (bbls)	**813,502**	504,860	540,590
Gas (mcf)	**18,046,197**	10,446,068	3,819,328
Oil equivalent (boe)	**3,821,202**	2,245,871	1,177,145
Crude oil and liquids (bbls/d)	**2,229**	1,379	1,481
Gas (mcf/d)	**49,442**	28,541	10,464
Oil equivalent (boe/d)	**10,469**	6,136	3,225
FINANCIAL			
($ thousands, except as noted)			
Revenue, net of royalties	**167,191**	76,966	36,736
Funds from operations	**137,454**	59,675	25,472
Per share basic	**2.94**	1.47	0.84
Net earnings	**50,075**	20,254	8,032
Per share basic	**1.07**	0.50	0.26
Per share diluted	**1.02**	0.48	0.25
Total assets	**827,263**	393,440	220,546
Total long-term financial liabilities	**175,481**	67,126	48,564
Cash and working capital (deficiency)	**(40,180)**	(13,439)	(15,942)
Basic outstanding shares	**49,345**	40,645	30,396
PER UNIT			
Gas ($/mcf)	**8.93**	6.86	6.54
Crude oil and liquids ($/bbl)	**55.73**	43.59	39.11
Revenue ($/boe)	**54.02**	41.69	39.59
Operating netback ($/boe)	**37.57**	28.30	23.86

CONTRACTUAL OBLIGATIONS

In the normal course of business Duvernay is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancelable.

Payments due by period *($ millions)*	Total	Less than 1 year	1-3 years	4-5 years	Thereafter
Long-term debt	$ 175.5	$ –	$ 175.5	$ –	$ –
Operating leases	1.9	0.5	1.1	0.3	–
Firm transportation agreements	6.4	2.5	3.6	0.3	–
	$ 183.8	$ 3.0	$ 180.2	$ 0.6	$ –

DRILLING RESULTS

The following table shows Duvernay's drilling results for the periods indicated.

	2005		2004	
	Gross	**Net**	Gross	Net
Crude oil	**4**	**3.2**	7	2.0
Natural gas	**120**	**80.7**	65	44.6
Suspended	**1**	**0.9**	1	0.5
Dry and abandoned	**1**	**1**	4	2.4
Total wells	**126**	**85.8**	77	49.5

LANDHOLDINGS

Duvernay's developed and undeveloped landholdings as at December 31, 2004 and 2005 are set forth below:

	Undeveloped		Developed		Total	
(Acres)	Gross	Net	Gross	Net	Gross	Net
2004						
Alberta	291,554	152,204	69,683	31,177	361,237	183,381
British Columbia	113,630	88,078	24,599	17,952	138,229	106,030
Total	405,184	240,282	94,282	49,129	499,466	289,411
2005						
Alberta	242,092	155,083	108,883	57,944	350,975	213,027
British Columbia	149,824	105,165	58,439	34,974	208,263	140,139
Total	**391,916**	**260,248**	**167,322**	**92,918**	**559,238**	**353,166**

CRITICAL ACCOUNTING ESTIMATES

The financial statements have been prepared in accordance with Canadian GAAP. A summary of significant accounting policies is presented in Note 1 to the financial statements. Certain accounting policies are critical to understanding the financial condition and results of operations of Duvernay.

PROVED OIL AND GAS RESERVES

Under Canadian Securities Regulations National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" (NI 51-101), "proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (it is likely that the actual remaining quantities recovered will exceed the estimated proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated reserves. There was no such consideration of probability under National Policy 2B (NP 2B). In the case of "probable" reserves, which are obviously less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the reporting company must believe that there is at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of reserve evaluation.

The oil and gas reserve estimates are made using all available geological, reservoir and historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Corporation's plans. The effect of changes in proved oil and gas reserves on the financial results and position of the Corporation is described under the heading "Full Cost Accounting for Oil and Gas Activities."

DEPLETION AND DEPRECIATION EXPENSE

Duvernay uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion and depreciation expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation expense.

FULL COST ACCOUNTING CEILING TEST

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

ASSET RETIREMENT OBLIGATIONS

The asset retirement obligation is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Abandonment costs per well are estimated to be $50,000 and are assumed to be incurred over a seven-year period commencing in 2010. Site by site estimates are added for significant facilities. Costs are inflated by 3% per year and a discount rate of 7% is assumed.

INCOME TAXES

The determination of the Corporation's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

EXPECTED CHANGES IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS AND MEASUREMENTS

In April 2005, a series of new accounting standards were released which established guidance for the recognition and measurement of financial instruments. These new standards include Section 1530 "Comprehensive Income," Section 3855 "Financial Instruments – Recognition and Measurement," and Section 3865 "Hedges." The new standards also resulted in a number of significant consequential amendments to other accounting standards to accommodate the new sections. The standards require all applicable financial instruments to be classified into one of several categories including: financial assets and financial liabilities held for trading, held-to-maturity investments, loans and receivables, available-for-sale financial assets, or other financial liabilities. The financial instruments are then included on a company's balance sheet and measured at fair value, cost or amortized value, depending on the classification. Subsequent measurement and recognition of changes in value of the financial instruments also depends on the initial classification. These standards are effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006 and must be implemented simultaneously. Duvernay has not yet assessed the full impact, if any, of these standards on the consolidated financial statements. However, the Corporation anticipates adoption of the new standards on January 1, 2007.

DC&P DISCLOSURE

Disclosure Controls and Procedures are controls and procedures designed and implemented by, or under the supervision of the issuer's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") to ensure that material information relating to the issuer is communicated to them by others in the organization as it becomes known and is appropriately disclosed as required under the continuous disclosure requirements of securities legislation. In essence, these types of controls are related to the quality and timeliness of financial and non-financial information in securities filings. An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures was conducted as of December 31, 2005, by and under the supervision of Duvernay's management, including the CEO and CFO. Based on this evaluation, the CEO and CFO have concluded that the Corporation's disclosure controls and procedures, as defined in Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, are effective to ensure that information required to be disclosed in reports that we file or submit under Canadian securities legislation is recorded, processed, summarized and reported within the time periods specified in those rules and forms. It should be noted that while the Corporation's Chief Executive Officer and Chief Financial Officer believe that the Corporation's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures will prevent all errors and fraud.

BUSINESS RISKS AND UNCERTAINTIES

Duvernay is exposed to numerous risks and uncertainties associated with the exploration for and the development, acquisition and production of crude oil and natural gas. Primary risks include the uncertainty associated with exploration drilling, changes in production practices, product pricing, industry competition and government regulation.

Drilling activities are subject to numerous technical risks and uncertainties of discovering commercially productive reservoirs. Duvernay attempts to offset exploration risk by utilizing trained professional staff and conducting extensive geological and geophysical analysis prior to drilling wells.

Duvernay utilizes sound marketing practices in an attempt to partially offset the cyclical nature of commodity pricing which is subject to external influences beyond Duvernay's control. Fluctuations in commodity pricing and foreign exchange rates may significantly impact Duvernay's revenue. The oil and natural gas industry is extremely competitive and success in competing with larger well-established competitors is not assured.

Duvernay monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations or taxation. In addition, Duvernay maintains a level of liability, property and business interruption insurance which is believed to be adequate for Duvernay's size and activities, but is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims.

ADDITIONAL INFORMATION

Additional information about Duvernay Oil Corp. may be found in documents filed on SEDAR at www.sedar.com and which are also available on Duvernay's website www.duvernayoil.com.

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF DUVERNAY OIL CORP.

The accompanying financial statements of Duvernay Oil Corp. and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors. The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the financial statements.

Management has established systems of internal controls, which are designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the Audit Committee, which is composed entirely of non-management directors. The Audit Committee has reviewed the financial statements with management and the auditors and has reported to the Board of Directors. The Board of Directors have approved the financial statements.

The financial statements have been audited on behalf of the shareholders by KPMG LLP, the external auditors, in accordance with auditing standards generally accepted in Canada.

Michael L. Rose
President and
Chief Executive Officer

Calgary, Alberta

March 22, 2006

Brian G. Robinson
Vice President, Finance
and Chief Financial Officer

Calgary, Alberta

TO THE SHAREHOLDERS OF DUVERNAY OIL CORP.

We have audited the balance sheets of Duvernay Oil Corp. as at December 31, 2005 and 2004 and the statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 22, 2006

BALANCE SHEETS

Year ended December 31	2005	2004
ASSETS		
Current assets:		
Cash and cash equivalents	**$ –**	$ 143
Accounts receivable	**58,215**	30,920
Prepaid expenses and deposits	**530**	962
	58,745	32,025
Property, plant and equipment (note 2)	**768,518**	361,415
	$ 827,263	$ 393,440
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 98,925**	$ 45,464
	98,925	45,464
Long-term debt (note 3)	**175,481**	40,724
Asset retirement obligation (note 4)	**9,491**	5,849
Future income tax (note 6)	**61,054**	20,553
Shareholders' equity:		
Share capital (note 5)	**396,450**	248,651
Contributed surplus (note 5)	**4,915**	1,327
Retained earnings	**80,947**	30,872
	482,312	280,850
Subsequent event (note 5)		
	$ 827,263	$ 393,440

See accompanying notes to financial statements.

On behalf of the Board:

RW Blakely

Director

M Ro

Director

STATEMENTS OF EARNINGS AND RETAINED EARNINGS

(Thousands of Dollars, Except Per Share Amounts)

Years ended December 31	2005	2004
Revenue:		
Petroleum and natural gas	$ 212,967	$ 96,692
Royalties	(41,447)	(18,010)
Transportation	(4,329)	(1,716)
	167,191	76,966
Expenses:		
Operating	21,396	12,069
General and administration	3,521	3,552
Stock-based compensation	3,881	1,165
Interest	3,592	926
Depletion, depreciation and accretion	60,091	27,237
	92,481	44,949
Earnings before taxes	74,710	32,017
Taxes (note 6):		
Capital	1,228	743
Future	23,407	11,019
	24,635	11,762
Net earnings	50,075	20,255
Retained earnings, beginning of year	30,872	10,617
Retained earnings, end of year	$ 80,947	$ 30,872
Earnings per share:		
Basic	$ 1.07	$ 0.50
Diluted	$ 1.02	$ 0.48

See accompanying notes to financial statements.

STATEMENTS OF CASH FLOWS

Year ended December 31		2005		2004
Cash provided by (used in):				
Operations:				
Net earnings	$	**50,075**	$	20,255
Items not involving cash:				
Depletion, depreciation, and accretion		**60,091**		27,237
Stock-based compensation		**3,881**		1,165
Future income taxes		**23,407**		11,019
Abandonment expenditures		**(300)**		-
Change in non-cash operating working capital *(note 8)*		**(15,301)**		(1,959)
		121,853		57,717
Financing:				
Issue of common shares, net of share issue costs		**127,656**		114,462
Increase in long-term debt		**134,757**		8,058
		262,413		122,520
Investments:				
Additions to property, plant, and equipment		**(441,822)**		(179,779)
Property acquisitions		**(15,748)**		–
Property dispositions		**31,262**		87
Change in non-cash working capital *(note 8)*		**41,899**		217
		(384,409)		(179,475)
Increase (decrease) in cash		**(143)**		762
Cash (bank indebtedness), beginning of year		**143**		(619)
Cash, end of year	$	**–**	$	143

Cash is defined as cash and cash equivalents.

See accompanying notes to financial statements.

NATURE OF OPERATIONS:

Duvernay Oil Corp. (the "Corporation") was incorporated under the laws of the Province of Alberta on June 27, 2001.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) Capital assets:

The Corporation follows the full-cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas properties and related reserves are capitalized. Such costs include land acquisition costs; cost of drilling both productive and non-productive wells, asset retirement costs and geological and geophysical expenses and overhead charges directly related to acquisition, exploration and development activities.

Capitalized costs, excluding costs relating to unproven properties and estimated salvage values, are depleted using the unit-of-production method based on estimated proven reserves of oil and gas before royalties as determined by independent petroleum engineers. For purposes of the depletion calculation, natural gas reserves and production are converted to equivalent volumes of crude oil based on relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to costs subject to depletion.

The Corporation applied a "ceiling test" to capitalized costs to ensure that the net costs capitalized do not exceed the estimated future net revenues from the production of its proven reserves, plus the cost of undeveloped land, less impairment. Future net revenues are calculated using the undiscounted cash stream assigned by independent reserve engineers adjusted for undeveloped land. Gains or losses on the disposition of oil and gas properties are not ordinarily recognized except under circumstances that result in a change in the depletion rate of 20% or more.

Gas processing facilities are amortized on a straight-line basis over their estimated life of 12 years.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives at a rate of 25%. Leasehold improvements are amortized straight-line over the life of the lease.

(b) Interest in joint ventures:

Substantially all of the Corporation's oil and gas exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Corporation's proportionate interest in such activities.

(c) Cash and cash equivalents:

Cash is defined as cash and investments with a maturity of three months or less.

(d) Per share amounts:

Basic per share amounts are calculated using the weighted average number of shares outstanding during the period. Diluted per share amounts are calculated using the treasury stock method. Diluted calculations reflect the weighted average incremental common shares that would be issued upon exercise of dilutive options and warrants assuming the proceeds would be used to repurchase shares at average market prices for the period. The weighted average number of shares outstanding is then adjusted by the net change.

(e) Future income taxes:

The Corporation uses the asset and liability method of income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using income tax rates enacted at the balance sheet date. The effect of a change in rates on future income tax liabilities and assets is recognized in the period that the change occurs.

(f) Use of estimates:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses during the reporting period. In particular, the amounts recorded for depletion of petroleum and natural gas properties and equipment and the asset retirement obligations are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. Actual results could differ from these estimates.

(g) Stock-based compensation plans:

The Corporation applies the fair value method for valuing stock option grants. Under this method, compensation cost attributable to all share options granted issued are measured at fair value at the grant and issuance date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options and warrants, consideration received, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital.

(h) Financial instruments:

The Corporation sells forward a portion of its future production through a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. Financial instruments are not used for speculative purposes. When the Corporation enters into a hedge it formally assesses, both at the hedges inception and on an ongoing basis, whether the derivatives that are used in the hedging transactions are highly effective in offsetting changes in fair value or cash flows of the hedged item. The derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas sales and cash flows in the same period in which the revenues associated with the hedged transactions are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract. Financial instruments that do not qualify as a hedge are recorded on a mark-to-market basis with the resulting gains or losses taken into income.

(i) Asset retirement obligations:

The fair value of the liability for the Corporation's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using the Corporation's credit adjusted risk-free interest rate and the corresponding amount recognized by increasing the carrying amount of property, plant and equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(j) Flow-through shares:

Flow-through shares are issued at a fixed price and the proceeds are used to fund qualifying exploration expenditures within a defined period. The expenditures funded by flow-through arrangements are renounced to investors in accordance with tax legislation. Share capital is reduced and future tax liability is increased by the total estimated future income tax costs of the renounced tax deductions in the period of renouncement.

(k) Revenue recognition:

Revenue from the sale of petroleum and natural gas is recognized during the month when title passes to an external party.

(l) Comparative information:

Certain comparative amounts have been reclassified to conform to current period presentation.

2. CAPITAL ASSETS:

2005	Cost	Accumulated depreciation	Net book value
Petroleum and natural gas properties	**$ 804,587,499**	**98,787,733**	**705,799,766**
Gas processing facilities	**67,292,986**	**4,868,206**	**62,424,780**
Furniture, fixtures and leasehold improvements	**676,394**	**383,012**	**293,382**
	$ 872,556,879	**104,038,951**	**768,517,928**
2004			
Petroleum and natural gas properties	$ 384,687,650	$ 42,653,267	$ 342,034,383
Gas processing facilities	20,798,152	1,658,877	19,139,275
Furniture, fixtures and leasehold improvements	517,727	276,662	241,065
	$ 406,003,529	$ 44,588,806	$ 361,414,723

The cost of unproven lands at December 31, 2005 of $114,239,000 (2004 – $51,005,000) has been excluded from the depletion calculation. Future development costs of proven reserves in 2005 of $156,997,000 (2004 – $67,408,000) have been included in the depletion calculation.

General and administrative expenditures of $1,707,000 (2004 – $1,750,000) have been capitalized and included as costs of petroleum and natural gas properties.

At December 31, 2005, the Corporation applied a ceiling test to its petroleum and natural gas assets using expected future market prices of:

Benchmark reference price forecast	2006	2007	2008	2009	2010	2011-2016
WTI ($US/bbl)	57.00	55.00	51.00	48.00	46.50	46.54
A.E.C.O. ($Cdn/mcf)	10.60	9.25	8.00	7.50	7.20	7.17

After 2016 the price forecast for WTI and AECO escalate at 2% per year to the end of the reserve life.

3. LONG-TERM DEBT:

The Corporation has a financing arrangement with a Canadian chartered bank for an extendible revolving term loan in the amount of $250 million. As at December 31, 2005, $175,481,417 (2004 – $40,724,440) of this term loan was drawn. The facility bears interest on a variable grid currently 95 basis points over the prevailing bankers' acceptance rate. Security for the facility includes a general security agreement and a $500 million demand loan debenture secured by a first floating charge over all assets. In May 2006, at the Corporation's discretion, the facility is available on a non-revolving basis for a period of 366 days, at which time the facility would be due and payable. Alternatively, the facility may be extended for a further 364-day period at the request of the Corporation and subject to approval by the bank. The Corporation is required to meet certain financial based covenants to maintain the facility.

4. ASSET RETIREMENT OBLIGATIONS:

The Corporation's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $17,775,000 (2004 – $10,592,000) which will be incurred between 2010 and 2017. A credit-adjusted risk-free rate of 7% and an inflation rate of 3% was used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	2005	2004
Balance, beginning of period	**$ 5,848,599**	$ 3,916,015
Accretion expense	**640,530**	382,619
Liabilities incurred	**3,301,848**	1,549,965
Liabilities settled	**(300,000)**	–
Balance, end of period	**$ 9,490,977**	$ 5,848,599

5. SHARE CAPITAL:

(a) Authorized:

Unlimited number of common shares and Class A common shares

Unlimited number of first preferred shares and second preferred shares, each issuable in series

(b) Common shares issued:

	Number of Shares	Amount
Balance, December 31, 2003	34,895,258	$ 131,642,587
For cash as initial public offering	5,000,000	52,500,000
For cash on private placement of flow-through shares	1,600,000	25,200,000
For cash on private placement	2,500,000	42,500,000
For cash on exercise of stock options	291,666	1,120,747
Contributed surplus on exercise of stock options	–	98,497
Share issue costs	–	(6,858,939)
Tax effect on share issue costs	–	2,448,000
Balance, December 31, 2004	44,286,924	248,650,892
For cash on private placement of flow-through shares	1,950,000	82,425,000
For cash on public share issue	1,800,000	49,950,000
For cash on exercise of stock options	598,384	2,427,451
For acquisition of properties	710,000	26,015,000
Contributed surplus on exercise of stock options	–	293,358
Share issue costs	–	(7,146,011)
Tax effect on share issue costs	–	2,415,000
Tax effect on flow-through renunciation	–	(8,581,000)
Balance, December 31, 2005	49,345,308	$ 396,449,690

In 2005, the Corporation issued 110,000 common shares to a company controlled by a director of Duvernay to purchase producing properties and 600,000 shares to an unrelated private oil and gas company to acquire their working interest in an area operated by the Corporation. The assets have been recorded at a value of $36,943,000, including $10,928,000 of future income tax liability.

On February 9, 2006, the Corporation completed a bought-deal private placement of 1,250,000 common shares at $44.50 per share for gross proceeds of $55,625,000.

(c) Flow-through Shares:

On April 5, 2005 Duvernay issued 1,150,000 common shares on a flow-through basis at an issue price of $35.50 per share for gross proceeds of $40.825 million. On October 18, 2005 the Corporation issued 800,000 common shares on a flow-through basis at an issue price of $52.00 for gross proceeds of $41.6 million. Effective December 31, 2005 the Corporation renounced $82.425 million to be incurred on qualifying expenditures on or before December 31, 2006. During the year ending December 31, 2005 Duvernay fulfilled its remaining obligation of $12.7 million of capital expenditures related to its 2004 flow-through offering of $25.2 million and has a commitment to renounce $82.425 million relating to its 2005 flow-through offering by December 31, 2006.

(d) Contributed surplus:

	2005	2004
Contributed surplus, December 31, 2004	**$ 1,327,450**	$ 260,881
Stock-based compensation	**3,880,700**	1,165,066
Exercise of stock options	**(293,358)**	(98,497)
Contributed surplus, December 31, 2005	**$ 4,914,792**	$ 1,327,450

(e) Stock options:

The Corporation has a rolling stock option plan. Under the employee stock option plan, the Corporation may grant options to its employees for up to 4,934,531 shares of common stock. The exercise price of each option equals the market price of the Corporation's stock on the date of grant and an option's maximum term is five years. Options are granted throughout the year and vest 1/3 on each of the first, second and third anniversaries from the date of grant.

Changes in the number of options, with their weighted average exercise price, are summarized below:

	2005		2004	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Stock options outstanding,				
beginning of year	**3,924,168**	**$ 6.55**	3,430,000	$ 4.33
Granted	**1,327,500**	**33.07**	792,500	15.12
Exercised	**(598,384)**	**4.06**	(291,666)	3.84
Forfeitures	**–**	**–**	(6,666)	3.50
Stock options outstanding, end of year	**4,653,284**	**$ 14.44**	3,924,168	$ 6.55
Exercisable, end of year	**2,392,451**	**$ 5.40**	2,075,001	$ 3.91

Range of exercise prices	Options outstanding: Number outstanding	Weighted average price	Weighted average remaining contractual life (years)	Options exercisable: Number exercisable	Weighted average price
$ 3.50 – 6.25	2,557,951	4.54	1.93	2,152,951	4.30
10.90 – 17.18	767,833	15.18	3.77	239,500	15.31
25.20 – 38.38	1,327,500	33.07	4.63	–	–
	4,653,284		3.00	2,392,451	5.40

Stock-based compensation:

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

Risk-free interest rate (%)	4.5
Expected life (in years)	3.5
Expected volatility (%)	40-50
Expected dividend	–
Expected forfeitures (%)	10

The weighted average fair value of the stock options granted during the year was $11.53 (2004 – $4.76) per option.

(f) Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the period ended December 31, 2005 was 46,832,318 (2004 – 40,644,585).

In computing diluted earnings per share for the period ended December 31, 2005, 2,118,880 (2004 – 1,762,697) shares were added to the weighted average number of common shares outstanding for the dilution from the stock options.

6. INCOME TAXES:

The provision for income taxes in the financial statements differs from the result, which would have been obtained by applying the combined federal and provincial tax rate to the Corporation's earnings before income taxes. This difference results from the following items:

		2005		2004
Earnings before taxes	$	**74,710,621**	$	32,016,413
Combined federal and provincial tax rate		**37.8%**		39.75%
Computed "expected" income tax expense	$	**28,236,879**	$	12,726,524
Increase (decrease) resulting from:				
Non-deductible Crown charges		**9,080,932**		4,689,952
Resource allowance		**(11,361,538)**		(5,165,603)
Effect of change in tax rate		**(4,083,000)**		(1,102,762)
Stock based compensation		**1,466,711**		463,114
Other		**67,116**		(592,225)
Future income taxes		**23,407,100**		11,019,000
Capital taxes		**1,228,000**		743,000
	$	**24,635,100**	$	11,762,000

The components of the Corporation's future income tax liability are as follows:

		2005		2004
Future tax assets:				
Asset retirement obligation	$	**3,207,000**	$	2,088,000
Share issue expenses		**3,550,000**		2,462,000
		6,757,000		4,550,000
Future tax liabilities:				
Property, plant and equipment		**(67,811,000)**		(25,103,000)
Net future tax liability	$	**(61,054,000)**	$	(20,553,000)

7. FINANCIAL INSTRUMENTS:

(a) Foreign currency exchange risk:

The Corporation is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices.

(b) Credit risk:

A substantial portion of the Corporation's accounts receivable is with customers and joint venture partners in the oil and gas industry and is subject to normal industry credit risks. Purchasers of the Corporation's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

(c) Fair value of financial instruments:

The carrying amounts of financial instruments included in the balance sheet approximate their fair value due to their short-term maturity, and long-term debt is carried at fair value because the terms and conditions are similar to those that the Corporation could negotiate for similar debt.

(d) Commodity price risk management:

As at December 31, 2005, the Corporation had fixed the price applicable to future production as follows:

Time period	Type of contract	Quantity control	Contract price
2006 January – June	Put (floor)	100 bbls/day	$50.00 U.S. W.T.I.
2006 January – March	Put (floor)	100 bbls/day	$50.00 U.S. W.T.I.
2006 April – June	Put (floor)	100 bbls/day	$50.00 U.S. W.T.I.
2006 July – September	Put (floor)	100 bbls/day	$50.00 U.S. W.T.I.
2006 January – March	Physical (swap)	15,000 gj's/day	$9.05 Cdn/gj average
2006 April –October	Physical (swap)	5,000 gj's/day	$9.32 Cdn/gj average
2006 January – March	Put (floor)	5,000 gj's/day	$9.00 Cdn/gj
2006 January – March	Put (floor)	2,000 gj's/day	$12.00 Cdn/gj
2006 April – October	Call (ceiling)	5,000 gj's/day	$9.65 Cdn/gj
2006 April – October	Call (ceiling)	2,000 gj's/day	$12.45 Cdn/gj
2006 April – October	Collar	2,000 gj's/day	$6.86 Cdn/gj Floor
			$9.66 Cdn/gj Ceiling
2006 April – October	Collar	3,000 gj's/day	$10.00 Cdn/gj Floor
			$11.00 Cdn/gj Ceiling

If the contracts were terminated at December 31, 2005, the Corporation would have to pay $1.2 million.

8. SUPPLEMENTAL CASH FLOW INFORMATION:

		2005		2004
Accounts receivable	**$**	**(27,295,003)**	$	(19,040,197)
Prepaid expenses		**432,000**		676,445
Accounts payable and accrued liabilities		**53,460,871**		16,622,258
Change in non-cash working capital	**$**	**26,597,868**	$	(1,741,494)
Relating to:				
Operations	**$**	**(15,301,217)**	$	(1,958,991)
Investments		**41,899,085**		217,497
Change in non-cash working capital	**$**	**26,597,868**	$	(1,741,494)
Interest and taxes paid:				
Interest paid	**$**	**(3,402,583)**	$	(926,636)
Taxes paid		**(899,172)**		(445,945)

DIRECTORS

CLAYTON H. RIDDELL
Chairman and Chief Executive Officer
Paramount Resources Ltd.
Calgary, Alberta

ROBERT W. BLAKELY
President
Likrilyn Capital Corporation
Toronto, Ontario

CHARLES J. BRUCE
Retired Geologist
(formerly, Manager,
Shell Canada Limited)

WILLIAM P. KIRKER
Independent Businessman
Calgary, Alberta

ALAN T. PETTIE
Partner
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

MICHAEL L. ROSE
President and Chief Executive Officer
Duvernay Oil Corp.
Calgary, Alberta

ROBERT N. YURKOVICH
Vice President, Exploration
Duvernay Oil Corp.
Calgary, Alberta

KEVIN J. KEENAN
Independent Businessman
Calgary, Alberta

OFFICERS

MICHAEL L. ROSE
President and Chief Executive Officer

ROBERT YURKOVICH
Vice President, Exploration

BRIAN ROBINSON
Vice President, Finance and
Chief Financial Officer

RICHARD KROL
Vice President, Marketing

DREW TUMBACH
Vice President, Land and Contracts

STAN NOWEK
Vice President, Operations
and Chief Operating Officer

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Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth and Palmer LLP
Calgary, Alberta

BANKERS

Bank of Nova Scotia
Calgary, Alberta

NOTICE OF ANNUAL GENERAL MEETING

The Annual General Meeting of the shareholders of Duvernay Oil Corp. will be held on June 8, 2006 at 3:00 p.m. in the McMurray Room at The Calgary Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta T2P 0L5.

ABBREVIATIONS

AEUB	Alberta Energy Utilities Board
ARTC	Alberta Royalty Tax Credit
bbls	barrels
bcf	billion cubic feet of gas
boe	barrel of oil equivalent using 6 mcf/boe for gas and 1 bbl/boe for crude oil and liquids
bbls/d	barrels per day
boe/d	barrels of oil equivalent per day
EP	Exploration and Production
gj	gigajoule
mbbl	thousand barrels
mboe	thousand boe
mcf	thousand cubic feet
mmbbl	million barrels
mmboe	million boe
mmcf	million cubic feet
mmcf/d	million cubic feet per day
mstb	thousand stock tank barrels
ngl's	natural gas liquids
NPW	new pool wildcat
TSX	Toronto Stock Exchange

Design and Production: Karo Design Calgary Inc. Printed in Canada

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